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## 4.0 INJECTION WELL CONSTRUCTION PLAN
## 40 CFR 146.82(a)(8), 146.87

## MARQUIS BIOCARBON PROJECT

### Facility Information

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Well name: MCI CCS 3

Well location: PUTNAM COUNTY, ILLINOIS
Non Responsive -- Geological information
[redacted]

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## 4.0 Injection Well Construction Plan ((146.86 (a)(1))

This section describes how a single, newly drilled injection well (MCI CCS 3) will be constructed at the Marquis BioCarbon Project site near Hennepin, Illinois, to meet the requirements of 40 CFR 146.82(a)(9)(11) and 40 CFR 146.86. The well design is discussed in detail in the following sections, including the drilling phase, materials to be used, and the initial expected design. Formation and casing depths for the injection well were determined using data from the MCI MW 1.

No completion stimulation is planned at this time because the expected reservoir quality is sufficient for the planned injection volumes. The maximum injection volume for this project is anticipated to be 1.5 million tonnes (MT)/year. No oil or gas zones are anticipated to be encountered at this location. The only expected zone that may present corrosion issues during the life of the project is the injection zone itself, the Mt. Simon Sandstone, as carbon dioxide ($CO_2$) is injected over time and mixes with the connate waters to form carbonic acid.

The reservoir modeling section of this application determined that a single, vertical injection well is sufficient to achieve the target $CO_2$ injection rate. The surveyed location of the well is shown in Figure 4-2. The proposed injection well diagram is shown in Figure 4-1. Table 4-1 details the depths of the geological formations of interest at the site. Refer to the Area of Review (AoR) and Corrective Action Plan (Permit Section 2) for further details on these formations.

Non Responsive -- Geological information

[redacted]

Table 4-1: Formations of Interest measured in *MCI MW 1 well*.

Non Responsive -- Geological information

[redacted]

Figure 4-1: MCI CCS 3 injection well schematic.

Non Responsive -- Geological information

[redacted]

Figure 4-2: Plot showing anticipated injection well location for MCI CCS 3.

## 4.1 Well Design (146.86 (b))

The proposed well design is shown above in Figure 4-1. The lithology of the injection and confining zones are shown with the injection depth, hole sizes and casing sizes and depths. These are discussed below.

### 4.1.2 Corrosiveness of the $CO_2$ stream and formation fluids (146.86 (b)(1)(v)(vi))

The anticipated chemical composition of the $CO_2$ stream is given in Table 4-2. Based on samples collected during normal operations and a fermentation drop at the ethanol-production facility, the injection stream will be composed of nearly pure $CO_2$, with a composition of 99.86% $CO_2$. A fermentation drop is considered the period during fermentation when the worst-case emissions from the scrubbers would be observed. The chemical balance of the remainder of the injection stream will be composed of trace constituents (nitrogen, oxygen, and triethylene glycol [TEG]) with quantities of approximately 0.1%, 0.03%, and 0.3 gallons (gal)/MMSCF, respectively. Dehydration may be performed to reduce the water vapor content in the injection stream. If dehydration is performed, the target water vapor concentration would be <50 parts per million (ppm) to limit the corrosivity of the injection stream. If dehydration is not incorporated into the process stream, water vapor may be present in the injection stream. The injection system has been designed with corrosive-resistant materials that contact the injection stream to prevent corrosion of the components caused by the presence of water vapor. Hydrogen sulfide ($H_2S$) is not expected to be present in the injection stream; however, analyses will be performed to identify its presence. A target concentration of $H_2S$ will be <20 ppm to reduce corrosivity of the injection stream.

The corrosivity of the injection stream should be limited given the quantities of the minor concentrations of the trace constituents in the injection stream, and the water content will be maintained below the regulated limit of <30 lb/MMSCF for CO2 transport pipeline standards.

| Component | Quantity |
|---|---|
| $CO_2$ | 99.86% |
| Oxygen | 0.03% |
| Nitrogen | 0.1% |
| TEG | <0.3 Gal/MMSCF |
| Water Vapor | 50 ppm |
| Hydrogen sulfide ($H_2S$) | <20 ppm |

Table 4-2: Chemical Composition of CO2 stream.

Table 4-3 presents the analytical results for parameters that may be used to assess the corrosivity of the formation waters in the Mt. Simon Sandstone. These data represent average results for the brine samples collected from the Mt. Simon Sandstone. The pH, conductivity, and TDS data represent analytical results from a commercial laboratory, the oxidation-reduction potential (ORP) data are field measurements made at the time the brine samples were collected, and the temperature value is the temperature measured at the mid-point of the formation through wireline logging.

Non Responsive -- Geological information

[redacted]

A summary of the measured downhole temperatures are shown in Table 4-4. Based on these measurements the temperature gradient between the top Eau Claire and base Mt. Simon is 0.0053 F/ft.

Non Responsive -- Geological information

[redacted]

Table 4-4: Downhole temperatures measured in characterization well, MCI MW 1 .

The data indicate that the formation brines are near neutral, but slightly acidic pH and have a moderate salinity content (Conductivity = 121.3 mS/cm and TDS = 59, 575 mg/L). In addition, the ORP measurements suggest that the brines exhibit reducing conditions and the temperature is slightly lower than what might be expected at a depth of approximately 3,990 ft (Mid Mt. Simon). Therefore, the native formation waters of the Mt. Simon Sandstone are not expected to be highly corrosive.

Although neither the CO2 stream or formation waters are expected to be highly corrosive, the injection materials that come in contact with the CO2 stream and/or reservoir brines will be constructed of corrosion-resistant materials, such as Cr13 steel, or similar. For example, the casing string across the Mt. Simon, the packer, and deep portion of the tubing with be constructed with corrosion-resistant materials.

### 4.1.1 Casing/Tubing

The well will be designed using carbon steel for the casing and tubulars that are not expected to be in contact with a mixture of the injectate ($CO_2$) and water. That is, the conductor, surface, and intermediate casing sections will all be carbon steel. The deep casing string will be constructed with corrosion-resistant chrome (CR13) across the reservoir and caprock to total depth (TD) and carbon steel from above the caprock to surface. This section of the wellbore is expected to have intermittent exposure to $CO_2$-formation water mixed fluids especially in the initial phases of injection and intermittently when well workovers are performed throughout the life of the project. Although the expected water content of the injectate stream will be less than 50 parts per million (ppm), the injection tubing string and flow-wetted injection tree components will be composed of corrosion resistant materials.

Specific pressure ratings for the tubulars are provided in Section 4.1.2. However, all selected casing and tubing grades and weights will be adequate for handling anticipated stress loads and pressures throughout the life of the project. The downhole tubulars were analyzed to ensure their ability to withstand the anticipated loads they may undergo. This analysis reviewed loads during installation, drilling, injection, workover, and subsequent abandonment. Additionally, effects due to cyclical loading, temperature, and exposure to wellbore fluids were also assessed. Table 4-3 details the minimum recommended tubulars and descriptions of key loads that were assessed. The design is robust, meeting industry accepted minimum safety factors with significant margin.

The injection well will include the following casing strings: a 30-inch diameter conductor string set at a depth of approximately 80 ft; a 20-inch diameter surface string set at a depth of approximately 350 feet (ft); a 13 3/8-inch diameter intermediate string set at a depth of approximately 2,750 ft; and a 9 5/8-inch-long string set at a depth of approximately 4,950 ft. All casing strings will be cemented to surface. Table 4-5 and Table 4-6 summarize the casing and tubing/packer program for the injection well. Any potential changes to the final well design will be discussed with the UIC Director or representative.

The deepest underground source of drinking water (USDW) was confirmed from the fluid sampling program during the characterization phase and was determined to be the Gunter Sandstone formation. Intermediate casing will be set through the Gunter and into the top of the Eau Claire caprock which will provide an additional layer of protection to the USDW.

| Casing String Name | Open Hole Size (in.) | Outside Diameter (in.) | Setting Depth (ft rGL) | Weight (lb/ft) | Wall Thickness (in.) | Grade | Connection |
|---|---|---|---|---|---|---|---|
| Conductor | +/-36" | 30 | 80 | 118 | 0.375 | X-42 | Welded |
| Surface | 26" | 20 | 350 | 94 | 0.438 | J/K-55 | Buttress or Long Round Thread |
| Intermediate | 17-1/2" | 13.375 | 2,750 | 54.5 | 0.38 | J/K-55 | Buttress or Long Round Thread |
| Long String | 12-1/4" | 9.625 | 4,970 | 40 | 0.395 | L-80 (0-2750') L-8013Cr (2750' – TD) | Premium |
| Injection Tubing | n/a | 4.5 | 3,200 | 11.6 | 0.25 | L-8013Cr | Premium |

Table 4-5: Casing details.

| Casing String Name | Outside Diameter (in.) | Weight (lb/ft) | Grade | Connection | Burst Rating (psi) | Collapse Rating (psi) | Tensile Yield(klbf) |
|---|---|---|---|---|---|---|---|
| Surface | 20 | 94 | J/K-55 | BTC | 2,108 | 520 | 1,480 |
| Intermediate | 13.375 | 54.5 | J/K-55 | BTC | 2,735 | 1,130 | 853 |
| Long String | 9.625 | 40 | L-80 (0-2750') 13Cr80 (2750' – TD) | Premium | 5,745 | 3,090 | 916 |
| Injection Tubing | 4.5 | 11.6 | L-8013Cr | Premium | 7,780 | 6,360 | 267 |

Table 4-6: Tubular performance details.

### 4.1.2 Tubular Stress Conditions (146.86 (c))

*Surface*

The surface casing will be the first string of casing installed by the drilling rig. The surface casing will be isolated behind two casing strings during injection operations, so the only applicable load conditions are during the installation of the surface casing and during drilling of the intermediate hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a 4.0 safety factor (SF) and meets design criteria. Axial loading will be minimal due to shallow setting depth, and all evaluated axial load cases result in SF that exceed 10 and meets design criteria. The worst-case collapse loading for the surface casing would be if returns are lost while drilling the intermediate hole interval; however, this results in a 3.4 SF and meets design criteria.

*Intermediate*

The intermediate casing will be the second string of casing installed by the drilling rig. The intermediate casing will not be exposed to injected fluids due to being isolated behind the long string. All applicable load conditions occur during the installation of the intermediate casing and during drilling of the production hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a 1.6 SF and meets design criteria. Axial loading will be minimal due to relatively shallow setting depth, and all evaluated axial load cases result in SF that exceed 3. The worst-case collapse loading for the intermediate casing occurs during cementing operations and results in a 1.5 SF which meets design criteria.

*Long String*

The long string is the final casing string that will be installed and will be exposed to installation and injection load cases. The upper portion of the string will be isolated by a tubing and packer completion allowing for use of carbon steel. The lower portion of the string that will be across the injection zone and caprock will use a corrosion resistant alloy (13Cr) as this string will be providing long term well integrity after the injection phase is completed and the well will be plugged. The highest evaluated burst load occurs when pressure testing the casing, which results in a 3 SF and meets design criteria. During normal operations, the burst loading on the long string casing due to applied annular pressure results (high) in a SF above 6. In the event the tubing develops a leak and maximum injection pressure is applied on a column of annular fluid, the resulting SF is 3.2; however, this will be a short-term event due to safety systems. Axial loading will be minimal due to shallow setting depth and minimal temperature fluctuations. All evaluated axial load cases result in SF that exceed 3. The worst-case collapse loading for the long string casing is a full evacuation to air which results in a SF of 1.4 which meets design criteria. This annulus will be filled with packer fluid (to minimize corrosion) and will be monitored to check for leaks; thus, this evacuated load case is extremely unlikely. A triaxial analysis was also performed based on the data from the MCI MW 1 well, resulting in a minimal SF of 2.4.

*Injection Tubing*

The injection tubing will be the final string of tubulars installed. The injection tubing will be the primary tubular in contact with injected fluids. During a workover event, the tubing may be removed from the well and can be replaced if any wall loss or damage has taken place. The highest burst load evaluated occurs when the tubing is pressure tested. This load results in a 4.3 SF which meets design criteria. Burst load during normal injection operations (maximum injection pressure, low annular pressure) results in a SF greater than 8. Burst load during injection with an annular pressure loss event results in a SF that exceeds 4. The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event, but still results in a SF of 2.8 and meets design criteria. Axial loading will be minimal due to shallow setting depth, low temperatures and all evaluated axial load cases result in SF that exceed 4.

### 4.1.3 Cement (146.86 (b))

The cemented casing strings (four in total) for the proposed injection well will all be cemented back to surface. The surface strings will be cemented using Class A, H, or G cement while the intermediate string will be cemented using Class H or G cement. The injection string will be installed using Schlumberger's EverCRETE (or equivalent) as the tail mix across the injection reservoir and caprock intervals with Class G or H as the lead above the caprock. Table 4-7 gives a summary of the cement types to be used for each casing string.

| Casing String | Appx. Depth Range (MDKB ft) | Cement Type |
|---|---|---|
| Surface | 0-350 | Class A, G, or H |
| Intermediate | 0-2,750 | Class G or H |
| Deep | 0-4,900 | $CO_2$-Resistant tail slurry /Class G or H: Pozzolan 50:50 lead slurry |

Table 4-7: Summary of cement types and corresponding casing strings.

Class A cements are adequate for providing zonal isolation in behind-pipe environments to prevent the movement of formation fluids between zones. Class A cements have been applied in shallow oil and gas wells and water disposal wells for many decades and are an accepted best practice. In a typical, non-corrosive subsurface environment (i.e., aquifer or oil/gas reservoirs) Class A cement will perform well throughout the service life of the well.

Class G or H cements are generally intended for use in deeper onshore wells and will have improved performance characteristics under higher temperature and pressure conditions, as compared to Class A cements (Guner & Ozturk, 2015).

The deep casing string will be cemented with a slurry similar to Schlumberger's EverCRETE system, which has been widely used in other carbon capture and storage (CCS) applications with reliable results. This cement system is useful in the injected $CO_2$ environment because it is highly resistant to carbonic acid, has very low permeability, and becomes self-healing when exposed to $CO_2$ (Schlumberger).

All casing strings will be cemented to surface. Table 4-8 describes the type of cement, estimated volumes, and weight of the mixture in pounds-per-gallon (ppg). Additives may change slightly based on laboratory testing. Volumes may be adjusted based on expected hole enlargement.

| Casing String | Casing Depth (MDKB ft) | Cement Description |
|---|---|---|
| Surface | 350 | Lead, Class A w/gel 13.2ppg 104bbls (50% excess)<br>Class A, 15.6 ppg, 54bbls (50% excess) |
| Intermediate | 2,750 | Lead, 50/50 Poz:Class H w/gel, 13.2 ppg, 400bbls (25% excess)<br>Tail, Class H, 16.4 ppg, 50bbls (25% excess) |
| Deep | 4,900 | Lead, 50/50 Poz:Class H w/gel, 13.2 ppg, 174bbls<br>Tail, $CO_2$-Resistant, 15.2 ppg, TOC 2700', 165bbls (25% excess) |

Table 4-8: Cement program for the $CO_2$ injection well.

### 4.1.4 Downhole Completion Equipment (146.86 (a)(2,3)

Completion equipment will exceed the ratings of the injection tubing and will be suitable for the downhole conditions. Completion equipment will be designed such that a tubing plug can be set in the tail pipe below the packer allowing for removal of the upper completion string during workover activities. The downhole completion equipment will include:

- $CO_2$ compatible packer with tail pipe to allow for Pressure / Temperature gauge and a profile for setting a tubing plug.
- Subsurface safety valve (SCSSV) to allow for shut-in of the well

The 4 ½-inch tubing will be set with a packer inside the long string casing to approximately 3,200 ft. The packer will be set at approximately 3,000 ft, which is about 250 to 275 ft below the top of the Eau Claire Caprock. Tubing tail pipe will be present below the packer to allow installation of a tubing plug and for retrievable memory pressure/temperature gauges to be set throughout the life of the well. A perforated joint of tubing may be required for the use of the pressure/temperature gauges, and this will be determined in the final design. Positive external pressure will be applied to the tubing string throughout the service life of the well from the annular fluid system (Section 4.7).

The final packer selection for this well will be determined prior to completion. However, preliminary plans suggest a packer similar to Baker Hughes' SC-2 retrievable production packer may be used for this application. The Baker SC-2 packer is designed for higher temperature and pressure environments where a high differential pressure (i.e., from above and below) may be present. Although a high-pressure differential will not be observed in this well, the design of this packer provides additional assurance of a positive seal. The exposed components of the packer will be specially constructed from $CO_2$-resistant materials including CR13 in addition to specially designed polymers for the elements. During the initial startup phase of injection, the packer may be exposed to $CO_2$-saturated brine from below until it is fully displaced from the wellbore by the $CO_2$.

An SCSSV will be deployed in the tubing string at +/-280 ft below surface. The SCSSV will prevent backflow of injected $CO_2$ up the tubing string back to surface in the unlikely event of loss of containment at surface. An appropriate corrosion-resistant material (stainless steel or Cr13) will be selected as the building material for the SCSSV and will be appropriately sized for the injection tubing string.

#### 4.1.5 Perforation Strategy

The perforated interval of the injection well will encompass selected targets throughout the Mt. Simon (approximately 3,226-4,800 ft). The perforated zones will range from one to six shots per foot (SPF) depending on the evaluation of the wireline logs of the MCI CCS 3. Perforated zones will be selected to balance well performance (i.e., injection pressure) with plume development. Because the Mt. Simon is expected to have some level of heterogeneity the final selected perforation intervals will largely depend on interpreted permeability layers within the Mt. Simon. Modeled perforation intervals based on data from MCI MW 1 well.

### 4.2 Drilling Contingencies

As mentioned in the previous section, the setting depths for the surface and intermediate casing strings are designed to provide maximum protection for both groundwater and USDWs. There are seven shallow groundwater wells within the AoR above 350 ft, five of which are owned by Marquis and used for ethanol production, and the other three are generally used in the area for agricultural applications.

The main drinking water source in the area are the shallow aquifers at approximately 300 ft measured depth (MD) and provide water to several municipalities in the region. The deepest USDW determined from testing in the MCI MW1 well is the Gunter Sandstone, approximately 2,130 ft MD. Two strings of casing (intermediate and deep) will provide protection to the USDW throughout the life of the project.

The largest drilling issue is anticipated to be the Potosi Dolomite (approximately 2,250 to 2,400 ft MD). This formation is widely known for its vugular, secondary porosity zones that can lead to lost circulation while drilling. Generally, it is thought to be more problematic deeper into the Illinois Basin to the south and east. However, it is a risk that the project will plan to manage at the project site. The Potosi formation did not present drilling problems during the installation of the MCI MW1 well. However, in the event circulation is nearly or completely lost, the plan is to drill ahead without drilling fluid returns through the remainder of the formation if possible. Then, a thixotropic cement slurry will be pumped, likely several slurries, to seal off the lost circulation zones. Once circulation has been fully restored drilling will proceed as planned.

In the event of severe lost circulation issues, a two-stage cement job may be implemented. The differential valve (DV) tool will be set just above the uppermost encountered lost circulation zone.

Although elevated pressures or hydrocarbons are not expected, Blow Out Prevention Equipment (BOPE) will be installed prior to drilling below the surface casing. Periodic drills and training will be performed to ensure the crews are educated in how to react to a well control event.

Other planned contingencies include standard oilfield practices for preventing excessive borehole deviation and a lost drill string. A stiff bottom-hole assembly (BHA), including stabilizers and/or drill collars, will be used to prevent significant deviation from vertical and to minimize the corkscrew tendency of the drill string. Intermittent deviation checks using single shot surveys will be used to verify that wellbore deviation stays below five degrees from vertical. Directional drillers will be contracted in the event consecutive deviation surveys show to be greater than five degrees from vertical to bring the wellbore back to near zero degrees.

Periodically throughout the drilling process the drill string will be pulled back up through the wellbore to ensure the hole is in good working condition, known as “wiper trips.” These short trips can prevent the buildup of formation cuttings around the outside of the drill string which can cause the string to become stuck in the hole, in the worst cases. They also ensure the formation of an even mud-cake layer along the walls of the wellbore which aids in better data collection with wireline tools in addition to a smoother installation of casing later in the process.

## 4.3 Annular Fluid System

The annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), or similar. The fluid will be mixed on site from dry salt and good quality (clean) fresh water, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The likely density of the annular fluid will be approximately 9.2 ppg. Final choice of the type of fluid will depend on availability and wellbore conditions.

The annulus fluid will contain additives and inhibitors including: a corrosion inhibitor, biocide (prevent growth of harmful bacteria), and an oxygen scavenger. Example additives and inhibitors are listed below along with approximate mix rates:

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars) – 10 gallons (gal) per 100 barrels (bbls) packer fluid
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbls packer fluid
- Spec-cide 50 (biocide) – 1 gal per 100 bbls packer fluid

- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbls packer fluid

These products were recommended by and are provided by Tetra Technologies, Inc., of Houston, TX. Actual comparable products and provider may be used other than those described above.

## 4.4 Stimulation Program

No stimulation program is being planned as the expected injectivity of the Mt. Simon Sandstone should be adequate for the planned injection volumes. A small volume of acid may be required to "clean the perforations" prior to injection but formation breakdown pressure will not be reached during the activity.

## 4.5 Demonstration of Mechanical Integrity

Pressure testing and logging will be performed to confirm the casing was installed correctly and cemented appropriately.

Please refer to the Pre-Operational Testing Plan (Permit Section 5) and the Testing and Monitoring Plan (Permit Section 7) for additional details on the demonstration of mechanical integrity.

## 4.6 References

Guner, D., Ozturk, H., 2015. Comparison of Mechanical Behavior of G Class Cements for Different Curing Time. Presented at 24th International Mining Congress and Exhibition of Turkey, 2015.

Schlumberger. EverCRETE system: https://www.slb.com/drilling/drilling-fluids-and-well-cementing/well-cementing/cemcrete-cementing-technology/evercrete-co2-resistant-cement-system.

## Appendix - EverCRETE

Transition Technologies

Schlumberger

Aligned with United Nations Sustainable Development Goals: 12—Responsible consumption and production, 13—Climate action.

# EverCRETE $CO_2$-resistant cement system

Extend cement barrier lifetime in reservoirs containing $CO_2$

**$CO_2$ Reduction:**
Serves as barrier for $CO_2$ storage wells or high $CO_2$-producing formations. Lowers $CO_2$ footprint during well construction due to significantly reduced usage of Portland cement.

**Temperature:**
up to 284 degF [140 degC]

### Applications

- Carbon capture and storage wells
- Wells in fields that use $CO_2$ injection for enhanced oil recovery (EOR)
- Primary cementing in $CO_2$ environments
- Long-term decommissioning objectives for plug and abandonment (P&A) in $CO_2$ environments

### How it improves wells

Because of its intrinsic low permeability, EverCRETE* $CO_2$-resistant cement system resists cement matrix attack from wet supercritical $CO_2$ and water saturated with $CO_2$ conditions. Accelerated reaction kinetics lead to a stabilized matrix within days of exposure to the $CO_2$ environment, leading to stabilized mechanical properties.

### How it works

EverCRETE system blends can be prepared locally using the standard bulk plant. The density can be tailored to well requirements, providing operational flexibility. Unlike other offerings, EverCRETE system is compatible with portland cement. The EverCRETE system can be used as a cement across potential $CO_2$-producing formations or as the primary barrier in the wellbore for any in situ fluids, with a portland cement-based slurry used as a filler slurry for coverage of remaining casing. It can be prepared and pumped using standard equipment. Additionally, the cement can be engineered with self-healing properties that are reactive to $CO_2$ exposure.



### What it replaces

Portland cement systems are used conventionally for zonal isolation in wells. However, portland cement is thermodynamically unstable in $CO_2$-rich environments and can degrade rapidly upon exposure to $CO_2$ in the presence of water. As $CO_2$-laden water diffuses into the cement matrix, the dissociated acid ($H_2CO_3$) reacts with the free calcium hydroxide and the calcium silicate hydrate (C-S-H) gel. The reaction products are soluble and migrate out of the cement matrix. Eventually, the compressive strength of the set cement decreases and the permeability and porosity increase, leading to loss of zonal isolation.

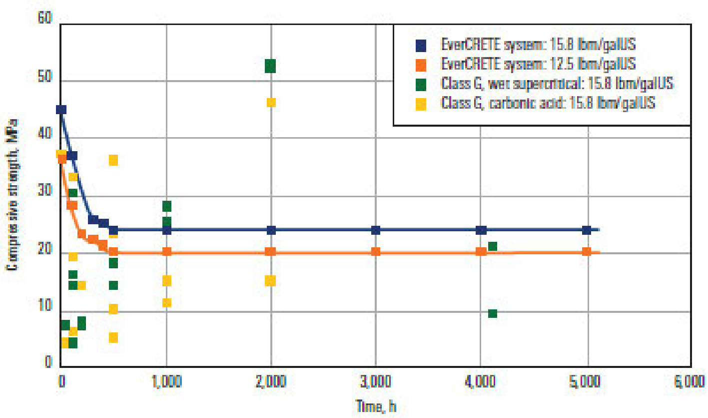
### Why it's ideal in any $CO_2$ environment

Well integrity has been identified as the biggest risk contributing to leakage of $CO_2$ from underground carbon capture and storage sites. EverCRETE system enables efficient underground storage and keeps greenhouse gases out of the atmosphere.

For wells in fields that use $CO_2$ injection for EOR or may use it in the future, EverCRETE system reduces the risk of cement sheath degradation and leakage. It can be used to cement new $CO_2$ injection wells or to plug and abandon injection or production wells at the end of the field life.

In case there is damage to the cement matrix and $CO_2$ starts to migrate, the self-healing capabilities that can be incorporated in EverCRETE system will repair the crack, reestablishing the integrity of the well and recovering zonal isolation.

EverCRETE system can also be used as a cement across potential $CO_2$-producing formations or as the primary barrier in the wellbore for in situ fluids after abandonment and permanent decommissioning.




*Compressive strength evolution of portland cement and EverCRETE system samples with time in wet supercritical $CO_2$ fluid and in $CO_2$ saturated in water at 194 degF [90 degC] under 28 MPa of pressure. After 6 months in $CO_2$-saturated water, the compressive strength of portland cement is not measurable because most of the samples are highly deteriorated. The stability of the EverCRETE system minimizes the degradation potential of the long-term barrier.*

*Mark of Schlumberger
Transition Technologies is a mark of Schlumberger.


slb.com/EverCRETE